UNITED STATES
NUCLEAR REGULATORY COMMISSION
REGION I
475 ALLENDALE ROAD
KING OF PRUSSIA, PA 19406-1415

February 14, 2011

Mr. Thomas P. Joyce
President and Chief Nuclear Officer
PSEG Nuclear LLC - N09
P.O. Box 236
Hancocks Bridge, NJ 08038

SUBJECT: HOPE CREEK GENERATING STATION - NRC INTEGRATED INSPECTION REPORT 05000354/2010005

Dear Mr. Joyce:

On December 31, 2010, the U.S. Nuclear Regulatory Commission (NRC) completed an inspection at the Hope Creek Generating Station. The enclosed inspection report documents the inspection results discussed on January 13, 2011, with Mr. Perry and other members of your staff.

The inspection examined activities conducted under your license as they relate to safety and compliance with the Commission's rules and regulations and with the conditions of your license. The inspectors reviewed selected procedures and records, observed activities, and interviewed personnel.

The report documents two NRC-identified findings of very low safety significance (Green) and one Severity Level IV violation. One of the findings was determined to involve a violation of NRC requirements. However, because of their very low safety significance and because they were entered into your corrective action program (CAP), the NRC is treating the Severity Level IV violation and the finding as non-cited violations (NCVs) consistent with Section 2.3.2 of the NRC Enforcement Policy. If you contest any NCV in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your denial, to the Nuclear Regulatory Commission, ATTN: Document Control Desk, Washington, DC 20555-0001; with copies to the Regional Administrator, Region I; the Director, Office of Enforcement, United States Nuclear Regulatory Commission, Washington, DC 20555-0001; and the NRC Resident Inspector at the Hope Creek Generating Station. In addition, if you disagree with the cross-cutting aspect assigned to any finding in this report, you should provide a response within 30 days of the date of this inspection report, with the basis for your disagreement, to the Regional Administrator, Region I, and the NRC Resident Inspector at the Hope Creek Generating Station.

In accordance with Title 10 of the Code of Federal Regulations (CFR) 2.390 of the NRC's "Rules of Practice," a copy of this letter, its enclosure, and your response (if any) will be available electronically for public inspection in the NRC Public Document Room or from the

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Sincerely,

Arthur L. Burritt, Chief
Projects Branch 3
Division of Reactor Projects

Docket No: 50-354
License No: NPF-57

Enclosure: Inspection Report 05000354/2010005
w/Attachment: Supplemental Information

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Sincerely,
/RA/
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U.S. NUCLEAR REGULATORY COMMISSION

REGION I

Docket No:	50-354
License No:	NPF-57
Report No:	05000354/2010005
Licensee:	PSEG Nuclear LLC (PSEG)
Facility:	Hope Creek Generating Station
Location:	P.O. Box 236 Hancocks Bridge, NJ 08038
Dates:	October 1, 2010 through December 31, 2010
Inspectors:	B. Welling, Senior Resident Inspector A. Patel, Resident Inspector J. Furia, Senior Health Physicist E. Gray, Senior Reactor Inspector T. Fish, Senior Operations Engineer M. Patel, Reactor Inspector L. Kern, Project Engineer
Approved By:	Arthur L. Burritt, Chief Projects Branch 3 Division of Reactor Projects

Enclosure

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SUMMARY OF FINDINGS

IR 05000354/2010005; 10/01/2010 - 12/31/2010; Hope Creek Generating Station; Operability Evaluations, Plant Modifications, Surveillance Testing.

This report covers a three-month period of inspection by resident inspectors and announced inspections by regional specialist inspectors. Two Green findings and one Severity Level IV NCV were identified. The significance of most findings is indicated by their color (Green, White, Yellow, or Red) and determined using Inspection Manual Chapter (IMC) 0609, "Significance Determination Process" (SDP). The cross-cutting aspect of a finding is determined using the guidance in IMC 0310, "Components Within The Cross-Cutting Areas." Findings for which the SDP does not apply may be Green or be assigned a severity level after NRC management review. The NRC's program for overseeing the safe operation of commercial nuclear power reactors is described in NUREG-1649, "Reactor Oversight Process," Revision 4, dated December 2006.

Cornerstone: Mitigating Systems

- Green. The inspectors identified a NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," because PSEG failed to identify and correct a condition adverse to quality. Specifically, PSEG did not identify that the reactor core isolation cooling (RCIC) turbine oil level was above the maximum level mark. Corrective actions performed by PSEG included restoring the proper oil level, revising the RCIC quarterly oil sample procedure conducting training for equipment operators, and reinforcing to senior reactor operators the significance of the oil levels on RCIC operability. The violation was entered into the CAP as notifications 20490150 and 20490446.

  The performance deficiency was more than minor because it affected the equipment performance attribute of the Mitigating Systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors performed a Phase I screening of the finding using IMC 0609, Attachment 0609.04, Table 4a, Mitigating Systems cornerstone. The inspectors determined the issue was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events. The finding had a cross-cutting aspect in the area of problem identification and resolution, because PSEG did not identify the RCIC turbine high oil level condition completely, accurately, and in a timely manner commensurate with its safety significance. (P.1(a)) (Section 1R22)

Cornerstone: Barrier Integrity

- Green. The inspectors identified a finding for a deficient operability evaluation involving leakage from the residual heat removal (RHR) system into the reactor building through a degraded gasket on the B RHR heat exchanger (HX). PSEG's operability evaluation did not fully account for the continuing degradation of the condition, and would have allowed the leakage rate from the HX to exceed the value analyzed in a supporting technical evaluation. Consequently, during the assumed mission time for the HX following a postulated accident, the post-accident control room dose could have exceeded the regulatory limit of 5 Rem. PSEG's corrective actions included revising both the operability and technical evaluations, and completing repairs to the RHR HX.

This finding is associated with the structure, system, and component (SSC) and barrier performance (Containment) attributes of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the performance deficiency is similar to IMC 0612, Appendix E, Example 3i, that states an issue with accident analysis calculations is more than minor if the calculations needed to be re-performed to assure accident analysis requirements were met. In this case, accident analysis calculations were re-performed to assure control room dose requirements were met. The inspectors determined that the finding was Green, based on a Phase 2 SDP review using Appendix H, "Containment Integrity." The finding had a cross-cutting aspect in the area of problem identification and resolution, because PSEG did not thoroughly evaluate the degraded condition on the B RHR HX, including classifying, prioritizing, and evaluating for operability. Specifically, PSEG's operability evaluation did not fully account for the dose impact of increased leakage during the post-accident mission time of the RHR HX. (P.1(c)) (Section 1R15)

- Severity Level IV. The inspectors identified a NCV of 10 CFR 50.59, "Changes, Tests, and Experiments," for PSEG's failure to perform an adequate safety evaluation for an approved design change involving primary containment isolation valves (PCIVs). Specifically, the safety evaluation did not identify the impact of a design change that increased the allowable closing stroke times of several PCIVs, which resulted in more than a minimal increase in the potential radiological consequences of an accident. PSEG's corrective actions included blocking procedure changes that incorporated the design change and implementing a new design change to return the PCIV stroke times back to their original design values.

Violations of 10 CFR 50.59 potentially impede or impact the regulatory process and are, therefore, dispositioned using the NRC Enforcement Policy. In accordance with the Enforcement Policy, the performance deficiency was more than minor because it is associated with the design control attribute of the Barrier Integrity cornerstone, and it adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. The inspectors performed a Phase I screening of the finding using IMC 0609, Attachment 0609.04,Table 4a, Barrier Integrity cornerstone. The issue screened as Green, because there was no actual open pathway in the physical integrity of the primary containment and because the design change, although approved for implementation, was not actually incorporated into station procedures. Therefore, the violation is categorized as Severity Level IV in accordance with Section 6.1.d of the NRC Enforcement Policy. The underlying finding had a cross-cutting aspect in the area of human performance, because the station did not provide proper supervisory and management oversight of work activities, including contractors. Specifically, engineers, supervisors, and managers did not properly oversee contractor engineering products, including performing a rigorous technical review of the products for a design change, that resulted in an inadequate 10 CFR 50.59 safety evaluation. (H.4(c)) (Section 1R18)

REPORT DETAILS

Summary of Plant Status

The Hope Creek Generating Station began the inspection period at full power. On October 4, the unit commenced end-of-cycle coastdown. On October 15, the unit was taken offline for refueling outage R16. On November 10, the reactor was taken critical following the refueling outage, and the unit achieved 100 percent power on November 16. The unit continued at full power for the remainder of the inspection period with the exception of planned power reductions for testing and/or rod pattern adjustments.

1. REACTOR SAFETY

Cornerstones: Initiating Events, Mitigating Systems, Barrier Integrity, and Emergency Preparedness

1R01 Adverse Weather Protection (71111.01 - 1 sample)

.1 Evaluate Readiness for Seasonal Extreme Weather Conditions

a. Inspection Scope

The inspectors completed one adverse weather protection inspection sample. The inspectors reviewed the scope of PSEG's cold weather preparations to verify that station personnel adequately prepared equipment to operate reliably in freezing conditions. Specifically, the inspectors performed a detailed review of PSEG's adverse weather procedures for seasonal extremes, discussed winterization with operations personnel, and walked down those portions of the service water (SW), fire protection, and condensate storage systems that could be impacted by cold temperatures. The inspectors verified that heat tracing and insulation used to protect these systems were functional and that system conditions were adequate to support operation in cold weather. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R04 Equipment Alignment (71111.04 - 3 samples)

.1 Partial Walkdown

a. Inspection Scope

The inspectors completed three partial walkdown inspection samples. The inspectors performed partial system walkdowns for the three systems listed below to verify the operability of redundant or diverse trains and components when safety equipment was unavailable. The inspectors completed walkdowns to determine whether there were discrepancies in the system's alignment that could impact the function of the system, and therefore, potentially increase risk. The inspectors reviewed applicable operating procedures, walked down system components, and verified that selected breakers, valves, and support equipment were in the correct position to support system operation. The inspectors also verified that PSEG had properly identified and resolved equipment alignment problems that could cause initiating events or impact the capability of mitigating systems or barriers and entered them into the CAP. The documents reviewed are listed in the Attachment.

- B control room ventilation system while the A control room ventilation system was out-of-service on October 4
- A RHR system in shutdown cooling while B RHR was out-of-service on October 21
- B and C SW systems while D SW system was out-of-service on November 18

b. Findings

No findings were identified.

1R05 Fire Protection (71111.05Q - 5 samples)

.1 Fire Protection - Tours

a. Inspection Scope

The inspectors completed five quarterly fire protection inspection samples. The inspectors conducted tours of the areas listed below to assess the material condition and operational status of fire protection features. The inspectors verified that combustibles and ignition sources were controlled in accordance with PSEG's administrative procedures; fire detection and suppression equipment was available for use; that passive fire barriers were maintained in good material condition; and that compensatory measures for out of service, degraded, or inoperable fire protection equipment were implemented in accordance with PSEG's fire plan. The areas toured are listed below with their associated pre-fire plan designator. The documents reviewed are listed in the Attachment.

- FRH-II-351, remote shutdown facility (service and radwaste area)
- FRH-II-412, RCIC pump and turbine room and electrical equipment room
- FRH-II- 413, high pressure coolant injection (HPCI) pump and turbine room and electrical equipment room
- FRH-II- 512, battery rooms
- FRH-II- 542, control equipment mezzanine

b. Findings

No findings were identified.

1R07 Heat Sink Performance (71111.07 - 1 sample)

a. Inspection Scope

The inspectors selected the A1 safety auxiliary cooling system (SACS) HX for review. The inspectors verified that biofouling programs existed and were managed in accordance with PSEG procedures and commitments to Generic Letter (GL) 89-13, "Service Water System Problems Affecting Safety-Related Equipment," and that HX performance data demonstrated satisfactory performance. The inspectors walked down the A1 SACS HX while it was open for inspection to identify potential fouling or degraded conditions. The inspectors also reviewed notifications in the CAP to verify that PSEG was identifying SACS HX problems at the appropriate threshold and that corrective actions addressed the identified problems and were effective. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R08 Inservice Inspection (ISI) (71111.08G - 1 sample)

a. Inspection Scope

The inspectors compared PSEG's Dissimilar Metal (DM) Weld program with the Electric Power Research Institute (EPRI) Boiling Water Reactor Vessel and Internal Projects 75A, "Technical Basis for Revisions to NRC GL 88-01 Inspection Schedules." The inspectors confirmed that the ultrasonic examinations of DM welds during refueling outage 16 (R16) plus the previously examined DM welds completed the intended ultrasonic testing (UT) examination scope of DM welds at the Hope Creek plant. The inspectors interviewed UT examination personnel and reviewed the nondestructive examination (NDE) qualifications, including EPRI Performance Demonstration Initiative certifications for the technicians responsible for the data collection, review, and interpretation of the inspection results.

A sample of NDE activities was inspected during R16. This included a review of the UT results using both manual UT techniques and the General Electric computer-based phased array UT system. This included DM nozzle to safe end welds to recirculation inlet nozzles, RPV1-N2ESE, RPV1-N5BSE, RPV1-N8BSE, RPV1-N2A with an overlay, N6, top head flange to pipe with phased array UT, and N8A nozzle to safe end weld. The UT of the weld overlay on N2A included the evaluation of a previously identified indication that was confirmed to have no growth since the last examination.

A sample of in-vessel visual inspection (IVVI) video records done per the IVVI procedure GEH-VT-204, Version 12, for jet pump components, core spray components, and the steam dryer were reviewed. The video quality was noted to meet or exceed the required VT-1 resolution. Test data for several visually identified indications, including those previously present, were assessed and confirmed to be evaluated by PSEG as part of the IVVI ISI process.

The work instruction package for the aspects of welding and nondestructive testing for the RHR flange repair was reviewed to confirm the requirements of the American Society of Mechanical Engineers (ASME) Code were met. The radiographs done per procedure OU-AA-335-005 on two 18" diameter RHR pipe welds made as part of the work package 60090119-5WD to correct an RHR HX flange leak were reviewed and compared to the ASME Code radiography requirements. The pre-service ultrasonic examination results for these RHR pipe welds were reviewed and compared to the ASME Code Section XI requirements.

The inspectors walked down portions of the outside of the drywell and the torus with a PSEG visual examiner to confirm the acceptance of a sample of visual examinations was in accordance with site procedures and ASME Code IWE requirements. External portions of the containment boundary were also observed at the location of the J-13, J-14, and J-37 penetrations and the 4" diameter drain lines from the air gap between the drywell steel and concrete to the torus room floor. Follow-up actions to notification 20411711 for leakage measured in drops per minute visible near the J-13 and J-14 penetrations during refueling outages, including change number 80101462, were also reviewed. This included examination of the scope and results of drywell shell ultrasonic thickness measurements above and below the J-13 penetration.

The inspection included discussions and a field tour with the Flow Accelerated Corrosion (FAC) and Buried Pipe Program Manager. The extent of FAC evaluations for 13 plant systems, including measurements of the reactor bottom head 2" diameter drain line, were reviewed. The scope of the buried pipe program as compared to the EPRI/Nuclear Energy Institute (NEI) industry program and current buried pipe program activities was included in the inspection scope. A sample of the areas of previous and current buried pipe excavations were walked down as part of the program evaluation. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R11 Licensed Operator Requalification Program (71111.11Q - 1 sample)

.1 Requalification Activities Review by Resident Staff

a. Inspection Scope

The inspectors completed one quarterly licensed operator requalification program inspection sample. The inspectors observed a licensed operator annual requalification simulator scenario (SG-644) on December 2, 2010, to assess operator performance and training effectiveness. The scenario involved a reactor water cleanup system leak, a loss of main condenser vacuum, and an anticipated transient without scram condition. The inspectors assessed simulator fidelity and observed the simulator instructors' critique of operator performance. The inspectors also observed control room activities with emphasis on simulator identified areas for improvement. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

.2 In-Office Review by Regional Specialist

a. Inspection Scope

In September 2010, the NRC completed its baseline inspection of the Hope Creek requalification program and documented results of that inspection in NRC inspection report (IR) 05000354/2010004. At the time of the baseline inspection, the facility training staff had not finished testing the operators. The staff completed testing in December 2010 and submitted test results to the NRC for review. On December 23, 2010, inspectors conducted an in-office review of those results. The inspection assessed whether pass rates were consistent with the guidance of IMC 0609, Appendix I, "Operator Requalification Human Performance Significance Determination Process (SDP)." The inspectors verified:

- Crew failure rate was less than 20 percent. (Crew failure rate was 0 percent)
- Individual failure rate on the dynamic simulator test was less than or equal to 20 percent. (Individual failure rate was 0 percent)
- Individual failure rate on the walk-through test was less than or equal to 20 percent. (Individual failure rate was 0 percent)
- Individual failure rate on the comprehensive written exam was less than or equal to 20 percent. (Individual failure rate was 0 percent)
- Overall pass rate among individuals for all portions of the exam was greater than or equal to 75 percent. (Overall pass rate was 100 percent)

b. Findings

No findings were identified.

1R12 Maintenance Effectiveness (71111.12Q - 3 samples)

a. Inspection Scope

The inspectors completed three maintenance effectiveness inspection samples. For the three systems and performance issues listed below, the inspectors evaluated items such as: appropriate work practices; identifying and addressing common cause failures; scoping in accordance with 10 CFR 50.65(b) of the Maintenance Rule; characterizing reliability issues for performance; trending key parameters for condition monitoring; charging unavailability for performance; classification and reclassification in accordance with 10 CFR 50.65(a)(1) or (a)(2); and appropriateness of performance criteria for SSCs/functions classified as (a)(2) and/or appropriateness and adequacy of goals and corrective actions for SSCs/functions classified as (a)(1). The documents reviewed are listed in the Attachment.

- RCIC system
- B standby liquid control (SLC) system
- B RHR HX gasket leakage

b. Findings

No findings were identified.

1R13 Maintenance Risk Assessments and Emergent Work Control (71111.13 - 4 samples)

a. Inspection Scope

The inspectors completed four maintenance risk assessment and emergent work control inspection samples. The inspectors reviewed on-line risk management evaluations through direct observation and document reviews for the following four plant configurations:

- A control room ventilation system out-of-service (emergent) and 5023 offsite power line out-of-service (planned) on October 4
- D SW pump and Salem Unit 3 gas turbine out-of-service for planned maintenance on November 18
- A SW pump and 5023 offsite power line out-of-service for planned maintenance on November 30
- B technical support center chiller, Salem Unit 3 gas turbine, and 5023 offsite power line out-of-service for planned maintenance on December 13

The inspectors reviewed the applicable risk evaluations, work schedules, and control room logs for these configurations to verify that concurrent planned and emergent maintenance and test activities did not adversely affect the plant risk already incurred with these configurations. PSEG's risk management actions were reviewed during shift turnover meetings, control room tours, and plant walkdowns. The inspectors also used PSEG's on-line risk monitor (Equipment Out of Service workstation) to gain insights into the risk associated with these plant configurations. Finally, the inspectors reviewed notifications documenting problems associated with risk assessments and emergent work evaluations. The documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R15 Operability Evaluations (71111.15 - 5 samples)

a. Inspection Scope

The inspectors completed five operability evaluation inspection samples. The inspectors reviewed the operability determinations for the degraded or non-conforming conditions associated with the following systems:

- B RHR HX increased leakage;
- B emergency diesel generator (EDG) after non safety-related breaker failed to trip during loss of offsite power (LOOP)/loss-of-cooling accident (LOCA) testing;
- C EDG frequency variations during surveillance testing;
- BX 501 transformer cable testing and potential degradation; and
- D, H, J and R safety relief valve (SRV) pilot valve leakage.

The inspectors reviewed the technical adequacy of the operability determinations to ensure the conclusions were justified. The inspectors also walked down accessible equipment to verify the adequacy of PSEG's operability determinations. Additionally, the inspectors reviewed other PSEG identified safety-related equipment deficiencies during this report period and assessed the adequacy of their operability screenings. The documents reviewed are listed in the Attachment.

b. <u>Findings</u>

Introduction: The inspectors identified a finding of very low safety significance (Green) for a deficient operability evaluation involving leakage from the RHR system into the reactor building through a degraded gasket on the B RHR HX. Specifically, PSEG's operability evaluation did not fully account for the continuing degradation of the condition, and would have allowed the leakage rate from the HX to exceed the value analyzed in a supporting technical evaluation. Consequently, during the assumed mission time for the HX following a postulated accident, the post-accident control room dose could have exceeded the regulatory limit of 5 Rem.

Description: In August 2009, PSEG discovered minor leakage from the B RHR HX into the RHR pump room. This leakage was categorized as engineered safety feature (ESF) leakage for the purposes of post-accident dose calculations. ESF leakage is one of three potential leakage pathways to the environment considered by these calculations. By May 2010, the leakage rate had increased to approximately 1 gallon per minute (gpm), and PSEG initiated a technical evaluation and an operability evaluation to support continued operability of the HX with this degraded condition.

PSEG's technical evaluation determined that the maximum allowed design basis ESF leakage under accident conditions could be increased by using a more realistic model of the actual control room envelope response following a LOCA. The technical evaluation stated that using this more realistic model, the maximum allowed RHR HX leakage rate could be as high as 7.0 gpm under accident conditions. The resulting control room dose based on this RHR HX leakage rate following a LOCA was then calculated to be 4.72 Rem.

During a review of the operability evaluation associated with the technical evaluation, the inspectors noted that it did not account for continuing degradation of the gasket that would result in an increase in leakage rate over the course of the assumed post-accident mission time of 30 days,. Therefore, inspectors determined that, due to the lack of consideration of this issue in the technical evaluation, the operability evaluation did not direct operators to isolate and remove the HX from service at a standby leakage rate low enough to ensure that the leakage rate under post accident conditions would not exceed the calculated leakage limit of 7.0 gpm over the course of the assumed HX accident mission time. Consequently, the resulting control room dose during an accident could have exceeded the regulatory limit of 5 Rem. This was inconsistent with PSEG procedure OP-AA-108-115, "Operability Determinations," Attachment 1, Section 2.3, which states that the evaluation should address whether the condition will continue to degrade and/or whether the potential consequences would increase.

As a result of the inspectors questions in this area, PSEG revised the technical evaluation and the operability determination. PSEG re-calculated the impact of the RHR HX leakage on the control room dose by revising the control room in-leakage data to reflect actual test results. Based on this re-calculation, PSEG concluded that the post-accident control room dose likely would not have exceeded regulatory requirements. Additionally, to ensure regulatory limits on control room dose were not exceeded, PSEG lowered the operability evaluation's limit on the measured HX leakage rate at which operators would be required to remove the HX from service.

PSEG also completed repairs to the RHR HX. PSEG installed a temporary housekeeping plate over the leaking flange of the HX to limit the rate of degradation of the HX gasket during the remainder of the operating cycle. During standby conditions, the maximum measured leakage rate for the gasket was 3.1 gpm, which would have corresponded to 6.5 gpm during accident conditions. During refueling outage R16, PSEG replaced the HX gasket and the leakage stopped.

Analysis: The performance deficiency was that Operability Evaluation 10-02, Revision 1, did not meet the standard established in PSEG procedure OP-AA-108-115, "Operability Evaluations," which states that an operability evaluation should address whether an identified degraded condition will continue to degrade and/or whether its potential consequences would increase. Specifically, the operability evaluation for B RHR HX gasket leakage did not account for the degradation that would occur during the assumed mission time of 30 days and as a result additional calculations were necessary to ensure design limits were not exceeded. This finding is associated with the structure, system, and component (SSC) and barrier performance (Containment) attributes of the Barrier Integrity cornerstone and adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. Specifically, the performance deficiency is similar to IMC 0612, Appendix E, "Examples of Minor Issues," Example 3i, that states an issue with accident analysis calculations is more than minor if the calculations needed to be re-performed to assure accident analysis requirements were met. In this case, accident analysis calculations were re-performed to assure control room dose requirements were met. The inspectors conducted a Phase 1 SDP screening in accordance with IMC 0609, Attachment 0609.04, "Initial Screening and Characterization of Findings," and determined that a Phase 2 review using IMC 0609, Appendix H, "Containment Integrity," was required. The issue is a Type B finding, as defined in Appendix H, because the degraded condition had implications for the integrity of containment but did not affect core damage frequency. The inspectors concluded that the finding screened as Green, based on Appendix H, Table 4.1 and Figure 4.1, because the affected system, RHR in suppression pool cooling or shutdown cooling, does not impact Large Early Release Frequency.

The finding had a cross-cutting aspect in the area of problem identification and resolution, because PSEG did not thoroughly evaluate the degraded condition on the B RHR HX, including classifying, prioritizing, and evaluating for operability. Specifically, PSEG's operability evaluation did not fully account for the dose impact of increased leakage during the post-accident mission time of the RHR HX. (P.1(c))

Enforcement: This finding does not involve enforcement action because no regulatory requirement violation was identified. Because this finding does not involve a violation and has very low safety significance, it is identified as a finding. **(FIN 05000354/2010005-01, RHR Heat Exchanger Deficient Operability Evaluation)**

1R18 Plant Modifications (71111.18 - 2 samples)

.1 Permanent Modifications

a. Inspection Scope

The inspectors completed a review of two permanent plant modification packages:

- RHR HX gasket replacement (DCP 60091119)
- PCIV stroke time changes (DCP 80096650)

This review verified that the design bases, licensing bases, and performance capability of the affected systems were not degraded by the modifications. The inspectors verified that the new configurations were accurately reflected in the design documentation, and that the post-modification testing was adequate to ensure the SSCs would function properly. The inspectors interviewed plant staff and reviewed issues that had been entered into the CAP to determine whether PSEG had been effective in identifying and resolving problems associated with plant modifications. The 10 CFR 50.59 safety evaluations associated with these modifications were also reviewed. Documents reviewed are listed in the Attachment.

b. Findings

Introduction: The inspectors identified a Severity Level IV NCV of 10 CFR 50.59, "Changes, Tests, and Experiments," for PSEG's failure to perform an adequate safety evaluation for an approved design change involving PCIVs. The safety evaluation did not identify the full impact of a design change that increased the allowable closing stroke times of several PCIVs and resulted in more than a minimal increase in the potential radiological consequences of an accident. During a postulated LOCA, the longer PCIV stroke times would have likely led to a previously unevaluated release of primary containment gases to the outside atmosphere, thereby increasing the dose to the control room, plant personnel, and the public.

Description: In December 2009, PSEG approved a 10 CFR 50.59 safety evaluation for design change request 80096650, which increased the allowable stroke times of numerous PCIVs to 120 seconds. The evaluation was supported by a technical evaluation (80096650-0210) that considered the impact of the design change on multiple systems that interfaced with primary containment. The conclusion of the 10 CFR 50.59 safety evaluation was that the design change could be implemented without prior NRC approval.

In July 2010, during the NRC's review of License Amendment Request H-09-01 for a Cobalt-60 isotope project, the NRC raised questions regarding the above-listed technical evaluation and a supporting calculation for the postulated post-LOCA radiological dose consequences. The NRC also submitted a number of Requests for Additional Information (RAIs) to PSEG to obtain information on the input data and methodology in these documents.

As PSEG was reviewing information to respond to the NRC RAIs, engineering personnel discovered deficiencies in the vendor-produced technical and safety evaluations. Among these deficiencies, engineers identified that the technical evaluation failed to fully assess the impact of the increased PCIV stroke times for the containment pre-purge and cleanup system. They determined that the increase in stroke times from 5 seconds to 120 seconds would lead to a longer duration blowdown for containment gases through this system. The gases would pass through system duct blowout panels into the torus room area and in the vent path toward the reactor building blowout panels. This condition would likely cause reactor building pressure to exceed the setpoint for the reactor building blowout panels. As a result, there would be an unfiltered release of containment gases through the reactor building blowout panels to the outside atmosphere, increasing the postulated dose to the control room and the public. This release was not considered in the calculation for dose consequences.

PSEG entered the deficiencies in their CAP as notifications 20470663 and 20474444. PSEG performed an apparent cause evaluation for these issues and determined that the primary causes were inexperienced engineering personnel who lacked technical knowledge of the plant design basis and design changes, lack of technical rigor, and overreliance on vendors. The technical evaluation and the 10 CFR 50.59 safety evaluation were performed by a vendor and PSEG engineers did not perform a thorough technical review of these products. Additionally, the apparent cause evaluation identified gaps in management oversight and compliance with design change procedures. Following identification of the deficiencies, PSEG took actions to stop procedure changes that incorporated the design change request for increasing the allowable PCIV stroke times. None of the allowable stroke times were revised, so there was no actual impact on the plant. Additionally, PSEG implemented a new design change request (DCR 80102144), which reverted the PCIV stroke times back to their original design values.

The inspectors noted that the deficiencies in the technical and safety evaluations were not identified until the NRC raised questions and issued RAIs during a review of a License Amendment Request. As such, the NRC prompted a more thorough review of the supporting information for the 10 CFR 50.59 safety evaluation, which revealed the underlying deficiencies and violation. Therefore, the inspectors concluded that this violation is NRC-identified.

Analysis: The performance deficiency was that PSEG did not perform an adequate safety evaluation for design change request 80096650 in accordance with the requirements of 10 CFR 50.59. Violations of 10 CFR 50.59 potentially impede or impact the regulatory process and are, therefore, dispositioned using the NRC Enforcement Policy. In accordance with the Enforcement Policy, the significance of a 10 CFR 50.59 violation is evaluated using the significance determination process. Using this process, the performance deficiency was determined to be more than minor because it was associated with the design control attribute of the Barrier Integrity cornerstone, and it adversely affected the cornerstone objective of providing reasonable assurance that physical design barriers protect the public from radionuclide releases caused by accidents or events. The inspectors performed an SDP Phase I screening for the finding using IMC 0609, Attachment 0609.04,Table 4a, Barrier Integrity cornerstone and the issue screened as Green, because there was no actual open pathway in the physical integrity of the primary containment and because the design change, although approved for implementation, was not actually incorporated into station procedures. Therefore, the violation is categorized as Severity Level IV in accordance with Section 6.1.d of the NRC Enforcement Policy.

The underlying finding had a cross-cutting aspect in the area of human performance, because the station did not provide proper supervisory and management oversight of work activities, including contractors. Specifically, engineers, supervisors, and managers did not properly oversee contractor engineering products, including performing a rigorous technical review of the products for a design change, which resulted in an inadequate 10 CFR 50.59 safety evaluation. (H.4(c))

Enforcement: Title 10 CFR 50.59(c)(2)(iii) requires, in part, that a licensee obtain a license amendment prior to implementing a proposed change, test, or experiment if the change, test, or experiment would result in more than a minimal increase in the consequences of an accident previously evaluated in the Final Safety Analysis Report (FSAR), as updated.

Contrary to the above, on December 16, 2009, PSEG did not obtain a license amendment prior to implementing a proposed change that would have resulted in more than a minimal increase in the consequences of an accident previously evaluated in the FSAR. Specifically, a 10 CFR 50.59 safety evaluation for design change request 80096650, which increased the stroke time for numerous PCIVs, resulting in a projected more than minimal increase in the consequences of a LOCA, was approved for implementation based on an incorrect conclusion that the design change could be implemented without prior NRC approval. Subsequently, in July 2010, following questions by the NRC, PSEG determined that the safety evaluation did not consider a potential release path from the containment pre-purge and cleanup system that would lead to more than a minimal increase in the radiological consequences of a LOCA, which was previously evaluated in Section 15.6.5 of the Updated FSAR. Because this violation was of very low safety significance, and it was entered into PSEG's corrective action program as notifications 20470663 and 20474444, this violation is being treated as an NCV, consistent with Section 2.3.2 of the NRC's Enforcement Policy. **(NCV 05000354/2010005-02, Inadequate 10 CFR 50.59 Safety Evaluation)**

1R19 Post-Maintenance Testing (71111.19 - 6 samples)

a. Inspection Scope

The inspectors completed six post-maintenance testing inspection samples. The inspectors reviewed the post-maintenance tests for the maintenance items listed below to verify that procedures and test activities ensured system operability and functional capability following completion of maintenance. The inspectors reviewed applicable test procedures to verify that they tested all safety functions potentially affected by the associated maintenance activities. The inspectors verified that for each potentially affected safety function the acceptance criteria stated in the procedure was consistent with the UFSAR and other design documentation. The inspectors also witnessed completion of the testing or reviewed the completed test results to verify satisfactory restoration of all safety functions affected by the maintenance activities. The documents reviewed are listed in the Attachment.

- RHR HX gasket replacement (DCP 60090119) on October 26
- A torus to drywell vacuum breaker limit switches replacement on October 28
- M SRV replacement on November 1
- C inboard main steam isolation valve stem and bonnet replacement on October 29
- HPCI 8278 valve replacement on November 2
- RCIC F045 valve planned corrective maintenance on November 9

b. Findings

No findings were identified.

1R20 Refueling and Other Outage Activities (71111.20 - 1 sample)

a. Inspection Scope

PSEG shut down Hope Creek on October 15, 2010, to begin its sixteenth refueling outage (R16). The inspectors reviewed the schedule and risk assessment documents associated with the Hope Creek R16 refueling outage to verify that PSEG appropriately considered risk, industry experience, and previous site-specific problems in developing and implementing an outage plan that maintained a defense-in-depth strategy. Prior to the refueling outage, the inspectors reviewed PSEG's outage risk assessment to identify risk significant equipment configurations and to determine whether planned risk management actions were adequate. The inspectors also verified that PSEG developed outage work schedules to manage personnel fatigue.

The inspectors verified that technical specification (TS) cooldown restrictions were adhered to by observing portions of the reactor shutdown and plant cooldown evolutions from the control room. The inspectors walked down the drywell following the reactor shutdown to identify possible sources of unidentified leakage and observe general equipment condition.

The inspectors verified that PSEG managed the outage risk in accordance with their outage plan. The inspectors confirmed that PSEG scheduled covered workers such that minimum days off for individuals working on outage activities were in compliance with 10 CFR 26.205(d)(4) and (5).

Refueling floor activities were observed periodically to verify whether refueling gates and seals were properly installed and to determine whether foreign material exclusion boundaries were established around the reactor cavity. The inspectors observed portions of new nuclear fuel receipt, inspection, and placement into new fuel racks. Core offload, reload, and shuffle activities were periodically observed from the control room and refueling bridge to verify that operators controlled fuel movements in accordance with station procedures.

The inspectors reviewed Hope Creek's implementation of a license amendment to place selected fuel assemblies that contain Co-59 isotope targets in the reactor core. The Co-59 targets are designed to transition to Co-60 during cycle irradiation. The inspectors confirmed that a maximum of 12 GE14i isotope test assemblies were loaded in the core, as described in TS 5.3.1. Additionally, the inspectors verified the isotope test assemblies were placed in non-limiting core regions.

The inspectors confirmed, on a sampling basis, that equipment clearance tags were hung or removed properly and that associated equipment was appropriately configured to support the function of the work activity. Equipment work areas were periodically observed to determine whether foreign material exclusion boundaries were adequate. During control room walkdowns and observations of plant evolutions, the inspectors verified that the instrumentation to measure reactor vessel level and temperature were within the expected range for the operating mode and that they were configured correctly to provide accurate indication. The inspectors periodically verified throughout the outage that electrical power sources were maintained in accordance with TS requirements and were consistent with the outage risk assessment. Walkdowns of control room panels, onsite electrical buses, and EDGs were conducted during risk significant electrical configurations to confirm the equipment alignments met requirements.

Risk significant plant evolutions were observed on a sampling basis during the outage, including reactor cavity flood up and drain down, installation and removal of main steam line plugs, installation and removal of the fuel pool gates, and RHR system transition to shutdown cooling mode of operation to verify adherence to station procedures and outage risk management plans.

The inspectors verified through daily plant status activities that the decay heat removal safety function was maintained with appropriate redundancy as required by TS and consistent with PSEG's outage risk assessment. Contingency plans, procedures, and staged equipment for a potential loss of decay heat removal were reviewed and compared to actual plant conditions to verify the effectiveness of mitigation strategies. During core offload conditions, the inspectors periodically determined whether the fuel pool cooling system was performing in accordance with applicable TS requirements and consistent with PSEG's risk assessment for the refueling outage. Reactor vessel water inventory controls and contingency plans were reviewed by the inspectors to determine whether they met TS requirements and provided for adequate inventory control. Secondary containment status and procedure controls were reviewed by the inspectors to verify that TS requirements and procedure requirements were met for secondary containment.

The inspectors walked down the containment drywell prior to reactor startup to verify no evidence of reactor coolant system (RCS) leakage and that debris was not left behind from outage work activities that could adversely impact suppression pool suction strainers. The inspectors verified on a sampling basis that TSs, license conditions, other requirements, and procedure prerequisites for mode changes were met prior to plant mode changes. The inspectors reviewed RCS leakage surveillance tests following plant startup to verify RCS integrity. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

1R22 Surveillance Testing (71111.22 - 5 samples)

a. Inspection Scope

The inspectors completed five surveillance testing (ST) inspection samples. The inspectors witnessed performance of and/or reviewed test data for the risk-significant STs listed below to assess whether the SSCs tested satisfied TSs, UFSAR, and procedure requirements. The inspectors verified that test acceptance criteria were clear, demonstrated operational readiness and were consistent with design documentation; that test instrumentation had current calibrations and the range and accuracy for the application; and that tests were performed as written with applicable prerequisites satisfied. Upon ST completion, the inspectors verified that equipment was returned to the status specified to perform its safety function. The documents reviewed are listed in the Attachment.

- B RHR HX flow measurement test on October 13
- B LOOP/LOCA test on October 16
- B SLC squib valve 18 month surveillance test on October 24
- RCIC inservice test on December 14
- Drywell leak detection sump monitoring system on December 28

b. Findings

Introduction: The inspectors identified a Green NCV of 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," because PSEG failed to identify and correct a condition adverse to quality. Specifically, PSEG did not identify that the RCIC turbine oil level was above the maximum level mark.

Description: During a plant walkdown on December 15, 2010, the inspectors observed the RCIC turbine oil level in the sight glass was above the maximum level mark. In response to this observation, PSEG operations personnel declared the RCIC system inoperable and established the proper oil level. The inspectors noted that PSEG had not previously identified the high oil level in the CAP.

Without leaks, RCIC turbine oil levels should remain relatively constant other than when draining oil for samples taken after the quarterly RCIC surveillance test run. Some equipment operators interviewed by inspectors stated that as a generally accepted practice, after draining the oil for the quarterly sample, they would refill the oil up to the maximum indication on the operator aid. The operators stated that this practice was acceptable because, if a leak in the reservoir did occur, the higher level would give them more time to detect and correct a degrading trend before the RCIC system was rendered inoperable. However, the inspectors noted that the vendor guidance for turbine oil systems recommended filling and maintaining the oil reservoir at or slightly above the minimum level. The guidance stated that high oil level can result in oil foaming during turbine operation. This can cause erratic turbine control and ultimately a turbine trip when oil foam comes in contact with the rotating overspeed trip assembly disc.

On December 14, after completing the quarterly pump run and oil sample, the operators filled the oil up to the maximum level in accordance with the common practice described above. However, PSEG determined that due to a minor steam leak located in the RCIC room, the added oil heated up and expanded. The inspectors determined that this expansion, combined with not using the vendor guidance for maintaining oil levels, caused the oil level to rise above the maximum allowable level mark. The inspectors concluded that the high oil level in the RCIC turbine reservoir was a condition adverse to quality.

PSEG performed the following corrective actions to address this issue:

- Reestablished the proper RCIC turbine oil levels;
- Changed the RCIC quarterly oil sample procedure to fill the oil level to just above the minimum oil level to account for oil expansion;
- Conducted training for nuclear equipment operators regarding these changes and the importance of maintaining the proper oil level in the RCIC turbine reservoir; and
- Reinforced to senior reactor operators the significance of the oil levels on RCIC operability.

The inspectors concluded that these corrective actions were appropriate.

Analysis: The inspectors determined that not identifying a condition adverse to quality, the high oil level in the RCIC turbine that could have prevented the RCIC system from performing its safety function, was a performance deficiency. The performance deficiency was more than minor because it affected the equipment performance attribute of the Mitigating Systems cornerstone objective of ensuring the availability, reliability, and capability of systems that respond to initiating events to prevent undesirable consequences. The inspectors performed a Phase I screening of the finding using IMC 0609, Attachment 0609.04, Table 4a, Mitigating Systems cornerstone. The inspectors determined the issue was of very low safety significance (Green) because the finding was not a design or qualification deficiency, did not result in an actual loss of safety function, and was not potentially risk significant for external events.

The finding had a cross-cutting aspect in the area of problem identification and resolution, because PSEG did not identify the RCIC turbine high oil level condition completely, accurately, and in a timely manner commensurate with its safety significance. (P.1(a))

Enforcement: 10 CFR 50, Appendix B, Criterion XVI, "Corrective Actions," requires, in part, that measures shall be established to assure that conditions adverse to quality, such as failures, malfunctions, deficiencies, deviations, defective material and equipment, and non-conformances are promptly identified and corrected. Contrary to the above, PSEG did not identify and correct a high out-of-specification oil level on the RCIC turbine before inspectors identified this condition on December 15, 2010. However, because the finding was of very low safety significance (Green) and has been entered into the CAP as notifications 20490150 and 20490446, this violation is being treated as a NCV, consistent with Section 2.3.2 of the NRC Enforcement Policy. **(NCV 05000354/2010005-03, RCIC Turbine Bearing High Oil Level)**

1EP6 Drill Evaluation (71114.06 - 1 sample)

a. Inspection Scope

The inspectors completed one drill evaluation inspection sample. The inspectors observed emergency plan response actions in the technical support center during a training drill on December 6, 2010. The inspectors verified that emergency classification declarations and notifications were completed in accordance with 10 CFR 50.72, 10 CFR 50, Appendix E, and the Hope Creek emergency plan implementing procedures. Documents reviewed are listed in the Attachment.

b. Findings

No findings were identified.

2. RADIATION SAFETY

Cornerstone: Radiation Safety - Public and Occupational

2RS1 Radiological Hazard Assessment and Exposure Controls (71124.01 - 1 sample)

a. Inspection Scope

Radiological Hazards Control and Work Coverage

During tours of the facility and review of ongoing work, the inspectors evaluated ambient radiological conditions. The inspectors verified that existing conditions were consistent with posted radiation work permits (RWPs) and worker debriefings, as applicable.

During job performance observations, the inspectors verified the adequacy of radiological controls, such as required surveys, radiation protection job coverage, and contamination controls. The inspectors evaluated PSEG's means of using electronic personal dosimeters in high noise areas as high radiation area (HRA) monitoring devices.

The inspectors verified that radiation monitoring devices placed on the body were consistent with the method that PSEG was employing to monitor dose from external radiation sources. The inspectors verified that the dosimeter was placed in the location of highest expected dose or that PSEG was properly employing an NRC-approved method of determining effective dose equivalent.

For high-radiation work areas with significant dose rate gradients (a factor of five or more), the inspectors reviewed the application of dosimetry to effectively monitor exposure to personnel. The inspectors verified that PSEG controls were adequate.

The inspectors reviewed RWPs for work within airborne radioactivity areas with the potential for individual worker internal exposures. The inspectors evaluated airborne radioactive controls and monitoring, including potentials for significant airborne contamination. For these selected airborne radioactive material areas, the inspectors verified barrier integrity and temporary high-efficiency particulate air ventilation system operation.

The inspectors examined PSEG's physical and programmatic controls for highly activated or contaminated materials stored within spent fuel and other storage pools. The inspectors verified that appropriate controls were in place to preclude inadvertent removal of these materials from the pool.

The inspectors conducted selective inspections of postings and physical controls for HRAs and very high radiation areas (VHRAs), to the extent necessary to verify conformance with the Occupational performance indicator.

Risk-Significant HRA and VHRA Controls

The inspectors discussed with the Radiation Protection Manager (RPM) the controls and procedures for high-risk HRAs and VHRAs. The inspectors verified that any changes to PSEG procedures did not substantially reduce the effectiveness and level of worker protection.

The inspectors discussed with first-line health physics supervisors the controls in place for special areas that have the potential to become VHRAs during certain plant operations. The inspector verified that PSEG controls for all VHRAs, and areas with the potential to become a VHRA, ensured that unauthorized individuals were not able to gain access to the VHRA.

Radiation Work Performance

During job performance observations, the inspectors observed radiation worker performance with respect to stated radiation protection work requirements. The inspectors determined that workers were aware of the significant radiological conditions in their workplace, the RWP controls/limits were in place, and that their performance reflected the level of radiological hazards present.

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be human performance errors. The inspectors determined that there was no observable pattern traceable to a similar cause. The inspectors determined that this perspective matched the corrective action approach taken by PSEG to resolve the reported problems. The inspectors discussed with the RPM any problems with the corrective actions planned or taken.

Radiation Protection Technician Proficiency

During job performance observations, the inspectors observed the performance of the radiation protection technician with respect to radiation protection work requirements. The inspectors determined that technicians were aware of the radiological conditions and the RWP controls/limits in their workplace and that their performance was consistent with their training and qualifications with respect to the radiological hazards and work activities.

The inspectors reviewed radiological problem reports since the last inspection that found the cause of the event to be radiation protection technician error. The inspectors determined that there was no observable pattern traceable to a similar cause. The inspectors determined that this perspective matched the corrective action approach taken by PSEG to resolve the reported problems.

b. Findings

No findings were identified.

2RS2 Occupational As Low As Reasonably Achievable (ALARA) Planning & Controls (71124.02)

a. Inspection Scope

Radiological Work Planning

The inspectors obtained a list of work activities from PSEG that were ranked by actual or estimated exposure that were in progress or that have been completed during the last outage, and selected work activities of the highest exposure significance.

The inspectors reviewed the ALARA work activity evaluations, exposure estimates, and exposure mitigation requirements. The inspectors determined that PSEG had reasonably grouped the radiological work into work activities based on historical precedence, industry norms, and/or special circumstances.

Radiation Work Performance

The inspectors observed radiation worker and radiation protection technician performance during work activities being performed in radiation areas, airborne radioactivity areas, and VHRAs. The inspectors concentrated on work activities that presented the greatest radiological risk to workers. The inspectors determined that workers demonstrated the ALARA philosophy in practice and that there were no procedure compliance issues. Also, the inspectors observed radiation worker performance to determine whether the training and skill level was sufficient with respect to the radiological hazards and the work involved.

b. Findings

No findings were identified.

4. OTHER ACTIVITIES

4OA1 Performance Indicator (PI) Verification (71151 - 5 samples)

a. Inspection Scope

Cornerstone: Mitigating Systems

The inspectors reviewed PSEG's submittals from the fourth quarter of 2009 through the third quarter of 2010 for the Hope Creek mitigating systems performance index (MSPI) PIs listed below. The inspectors used definitions and guidance contained in NEI 99-02, "Regulatory Assessment Indicator Guideline," Revision 6, to verify the basis in determining the availability and reliability criteria for the applicable systems.

- Heat removal system (RCIC)
- Emergency AC power system (EDGs)
- RHR system
- HPCI system
- Support cooling water system (SW and safety auxiliary cooling)

The inspectors reviewed the consolidated data entry MSPI derivation reports for the unavailability and unreliability indexes for the monitored systems; the monitored component demands and demand failure data for the monitored systems; and train and system unavailability data for the monitored systems. The inspectors verified the accuracy of the data by comparing it to CAP records, control room operators' logs, maintenance rule performance and scope reports, system performance/health reports, the equipment/operability issues database, the site operating history database, key PI summary records, operating data reports and the MSPI basis document.

b. Findings

No findings were identified.

4OA2 Problem Identification and Resolution (71152 - 1 annual sample; 1 semi-annual trend sample)

.1 Routine Review of Items Entered into the CAP

a. Inspection Scope

As required by IP 71152, Identification and Resolution of Problems, and in order to help identify repetitive equipment failures or specific human performance issues for follow-up, the inspectors performed a daily screening of all items entered into PSEG's CAP. This was accomplished by reviewing the description of each new notification and attending management review committee meetings.

b. Findings

No findings were identified.

.2 Annual Sample: EDG Fuel Oil Storage Tank Contamination Issues

a. Inspection Scope

The inspectors performed an in-depth review of PSEG's corrective actions for EDG fuel oil storage tank contamination issues documented in notifications in 20489106 and 20489107. PSEG had identified the unexpected increases in fuel oil storage tank contamination levels that could have been indicative of fuel issues within the system. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings were identified.

The inspectors determined that PSEG adequately evaluated the increase in particulates in the C EDG diesel fuel oil storage tanks. PSEG identified the increased in particulates in the diesel fuel oil storage tanks since March 2010. TSs state any levels above 10 milligrams per liter (mg/L) could affect diesel operation. The most recent particulate levels had increased to 8.0 mg/L. The inspectors questioned whether the C EDG could perform its design function given the increased particulates of 8.0 mg/L and whether it would exceed 10 mg/L during its 24 hour mission time.

PSEG performed a technical evaluation to address the inspectors' question, which was documented in notification 20489855. PSEG concluded there is no correlation between run time and particulate level increases, therefore the particulate levels would remain below the operability limit of 10 mg/L. The inspectors noted that the diesel fuel oil storage tanks were originally scheduled to be cleaned in March 2011. PSEG has actions in place to clean the tanks in January 2011, earlier than originally scheduled. The inspectors also noted that the particulate levels had increased shortly before the scheduled 10 year cleaning. PSEG has determined that this frequency is adequate because the tanks are sampled quarterly and a notification is written to address any increase in particulate levels above 4 mg/L. PSEG also has actions in place to analyze the high oil particulates and determine the cause of the increase in particulates. The inspectors concluded these actions were adequate.

.3 Semi-Annual Review to Identify Trends: Corrective Action Backlogs

a. Inspection Scope

The inspectors performed a semi-annual review of site issues to identify trends that might indicate the existence of more significant safety issues, as required by Inspection Procedure 71152, "Identification and Resolution of Problems." The inspectors included in this review repetitive or closely-related issues that may have been documented by PSEG outside of the CAP, such as trend reports, PIs, major equipment problem lists, system health reports, maintenance rule assessments, and maintenance or CAP backlogs. The inspectors also reviewed the PSEG CAP database for the third and fourth quarters of 2010 to assess notifications written in various subject areas (equipment problems, human performance issues, etc.), as well as individual issues identified during the NRC's daily notification review (Section 4OA2.1).

The inspectors focused on potential trends in corrective action backlogs. The inspectors examined PSEG's corrective action backlog lists. This review was evaluated against the PSEG's CAP and 10 CFR 50, Appendix B, to determine if PSEG's cumulative review of corrective action backlogs identified trends in degraded equipment backlogs. Documents reviewed are listed in the Attachment.

b. Findings and Observations

No findings were identified.

The inspectors evaluated a sample of corrective action backlog lists. This review included a sample of equipment issues that were scheduled to be corrected over the course of the past two quarters to objectively determine whether issues either were appropriately corrected or ruled as emerging or adverse trends. The inspectors also verified the appropriate disposition of corrective action backlog trends and that they were addressed within the scope of the CAP and documented in notifications.

Examples of equipment in PSEG's corrective action backlogs include the HPCI, RCIC, EDGs, RHR, and core spray systems. The inspectors determined that PSEG appropriately identified corrective actions that were past due and appropriately justified the required extension requests. The inspectors recognized that extensions were also based on risk significance of issues and those with higher risk significance were either not extended or corrective actions were in place to correct the deficiencies in a timely matter.

The inspectors concluded that PSEG was implementing appropriate actions to address any adverse trend in corrective action backlogs.

4OA5 Other Activities

.1 Operation of an Independent Spent Fuel Storage Installation (ISFSI) at Operating Plants (60855.1)

a. Inspection Scope

The inspectors verified by direct observation and independent evaluation that PSEG had performed loading activities at the ISFSI in a safe manner and in compliance with applicable procedures. The inspectors toured the ISFSI, observed the performance of radiological surveys, and reviewed radiological surveys performed during the past 12 months.

b. Findings

No findings were identified.

.2 (Closed) Unresolved Item (URI) 05000354/2009007-04, Design of the Degraded Voltage Protection Scheme

During the 2009 component design basis inspection, a URI was identified with respect to the Hope Creek Generating Station degraded voltage protection scheme. The concern was that the existing scheme may not be in direct conformance with the guidance provided in the Office of Nuclear Reactor Regulation branch technical position (PSB-1) that was developed to establish a technical position for the adequacy of station electric distribution system voltages. The URI was opened to review Hope Creek Generating Station's licensing basis with respect to the guidelines contained in the branch technical position and postulated degraded voltage scenarios. The URI identified a potential concern that, under the existing scheme, a postulated degraded grid scenario had the potential to automatically transfer a bus with a degraded source voltage to an alternate source that may also become degraded as a result of the increased loading. A second issue involved a concern with the adequacy of the degraded voltage relay time delays and consistency with the existing accident analysis assumptions for cooling water injection to the core following a LOCA.

PSEG initiated a review of the issue in accordance with their CAP under notification 70105083 OP 0220, Evaluate Hope Creek 4.16 kV 1E Undervoltage Relay Scheme. PSEG concluded within their evaluation of the two concerns that their existing scheme provided adequate protection and was consistent with their approved licensing bases. PSEG determined that the Hope Creek Generating Station's undervoltage scheme was reviewed and determined to be adequate per Safety Evaluation Report section 8, Electric Power Systems, and was within the licensing basis assumptions of LOCA concurrent with the loss of offsite power. The inspectors noted this position regarding the electrical scheme was consistent with previous NRC reviews of the issue. The degraded time delay relay scheme was previously reviewed and concluded to be in compliance with the licensing bases in NRC IR 05000354/2004004.

PSEG reviewed the issue within their CAP in response to the URI and concluded that the postulated scenario of concern was outside of the station's licensing bases because it requires the station to postulate a sustained 92 percent degraded grid condition concurrent with a LOCA and selected operation of degraded voltage relays. PSEG determined that the proposed scenario is not credible because the existing scheme would not allow the postulated bus transfers to occur. PSEG determined that during the proposed scenario the station service transformers would continue to drop nominal voltage from the 92 percent starting point, due to progression of the LOCA sequencer. Unless the voltage recovers above 92 percent, the voltage drop incurred by each station service transformer would ensure the 92 percent blocking scheme would not allow even the first transfer to occur to the alternate source and the loads would go to the EDGs.

The inspector reviewed this position and determined that this was a reasonable conclusion.

PSEG also concluded that their existing time delay setpoints were adequate. From a design consideration, the second undervoltage relay time delay allowable setting of 15 - 35 seconds ensures that locked rotor conditions for any single motor will not result in separation from the preferred offsite power source. The inspectors noted that the time delay setpoint scheme was also reviewed and concluded to be appropriate in a 1992 design inspection. The undervoltage scheme was reviewed and the results documented within Electrical Distribution System Functional Inspection Report 50-354/92-80 and subsequently in 1993 in NRC IR 50-354/93-23.

The inspectors reviewed PSEG's corrective actions, evaluations of the URI concerns, licensing basis information, postulated scenario of degraded 4kV vital bus concurrent with LOCA, previous URIs regarding degraded grid time delay relay settings, and previous IRs and determined that PSEG was in conformance with their approved licensing basis and there was no finding or violation of NRC requirements.

.3 Institute of Nuclear Power Operations (INPO) Plant Assessment Report Review

a. Inspection Scope

The inspectors reviewed the final report for the INPO plant assessment of the Hope Creek Generating Station conducted in May 2010. The inspectors reviewed the report to ensure that issues identified were consistent with the NRC's perspectives of licensee performance and to identify significant safety issues that required further NRC follow-up.

b. Findings

No findings were identified.

.4 Typographical Correction to NRC Integrated Inspection Report 05000354/2010004

NRC IR 05000354/2010004, dated November 8, 2010, Attachment page A-1, contained a typographical error. Licensee Event Report (LER) 05000354/2010-001-00 was listed incorrectly as LER 05000354/2010004-001-00. All other references to this LER in the inspection report were correct.

4OA6 Meetings, including Exit

On January 13, 2011, the inspectors presented inspection results to Mr. J. Perry and other members of his staff. The inspectors asked PSEG whether any materials examined during the inspection were proprietary. No proprietary information was identified.

ATTACHMENT: SUPPLEMENTAL INFORMATION

SUPPLEMENTAL INFORMATION

KEY POINTS OF CONTACT

Licensee Personnel

J. Perry, Hope Creek Site Vice President
L. Wagner, Hope Creek Plant Manager
E. Carr, Operations Director
E. Casulli, Shift Operations Superintendent
K. Chambliss, Work Management Director
P. Duca, Senior Engineer, Regulatory Assurance
M. Gaffney, Regulatory Assurance Manager
K. Knaide, Engineering Director
W. Kopchick, Plant Engineering Manager
F. Mooney, Maintenance Director
H. Trimble, Radiation Protection Manager
R. Boesch, Operations Training Manager

LIST OF ITEMS OPENED, CLOSED, AND DISCUSSED

Opened/Closed

05000354/2010005-001	FIN	RHR Heat Exchanger Deficient Operability Evaluation (Section 1R15)
05000354/2010005-002	NCV	Inadequate 10 CFR 50.59 Safety Evaluation (Section 1R18)
05000354/2010005-003	NCV	RCIC Turbine Bearing High Oil Level (Section 1R22)

Closed

05000354/2009007-004	URI	Degraded Voltage Protection Scheme Design (Section 4OA5)

LIST OF DOCUMENTS REVIEWED

In addition to the documents identified in the body of this report, the inspectors reviewed the following documents and records:

Hope Creek Generating Station UFSAR
Technical Specification Action Statement Log
HCGS Operator Narrative Logs
Hope Creek Operations Night Orders and Temporary Standing Orders

Section 1R01: Adverse Weather Protection

Procedures
HC.OP-GP.ZZ-0003, Station Preparations for Winter Conditions, Revision 24
WC-AA-107, Seasonal Readiness, Revision 10

Notifications(*NRC-identified)
20488723*

Drawings
M-8-0, Condensate and Refueling Water Storage and Transfer, Revision 34
M-10-1, Service Water, Revision 52
M-22-0, Fire Protection System, Revision 27

Other Documents
2010 Hope Creek Winter/Grassing Seasonal Readiness Affirmation dated November 1, 2010

Section 1R04: Equipment Alignment

Procedures
HC.OP-SO.GJ-0001, Control Area Chilled Water System Operation, Revision 51
HC.OP-SO.BC-0001, Residual Heat Removal System Operation, Revision 47
HC.OP-SO.EA-0001, Service Water System Operation, Revision 34

Notifications
20479749

Drawings
M-90-1, Auxiliary Building Control Area Chilled Water System, Revision 16
M-10-1, Service Water, Revision 52

Section 1R05: Fire Protection Measures

Procedures
FRH-II-542, Control Equipment Mezzanine 124', Revision 9
FRH-II-412, RCIC Pump and Turbine Room and Electrical Equipment Room, Revision 3
FRH-II-413, HPCI Pump and Turbine Room and Electrical Equipment Room, Revision 3
FRH-II-351, Service and Radwaste Area 137', Revision 6
FRH-II-512, Battery Rooms 54', Revision 5

Notifications (*NRC identified)
20481025* 20488889* 20490436* 20490212*

Section 1R07: Heat Sink Performance

Procedures
ER-AA-340-1002, Service Water Heat Exchanger and Component Inspection Guide, Revision 3
HC.OP-AB.COOL-0002, Safety/Turbine Auxiliaries Cooling System, Revision 3
HC.OP-SO.EG-0001, Safety and Turbine Auxiliaries Cooling Water System Operation, Revision 39

ER-AA-340, GL 89-13 Program Implementing Procedure, Revision 3
HC.OP-FT.EA-0001(Q), Validating SSWS Flow Through SACS HXs, Revision 7
HC.SE-PR.EG-0001(Q), Safety and Auxiliary Cooling System Annual Biofouling Monitoring, Revision 5

Drawings
M-11-1 Sh. 1, Safety Auxiliaries Cooling Reactor Building, Revision 29
M-12-1 Sh. 1, Safety Auxiliaries Cooling Auxiliary Building, Revision 31

Orders
30138487 30138488

Other Documents
H-1-EG-MEE-1301, 100°F SACS Design Temperature Limit Evaluation, Revision 2
Generic Letter 89-13, Service Water System Problems Affecting Safety-Related Equipment

Section 1R08: Inservice Inspection

Procedures
OU-AA-335-018, VT-1 and VT-3 Visual Examination of ASME Class MC and CC Containment Surfaces and Components, Revision 2
EPRI-DMW-PA-1, Procedure for Manual Phased Array Ultrasonic Examination of Dissimilar Metal Welds, Revision 1
EPRI-WOL-PA-1, Procedure for Manual Phased Array Ultrasonic Examination of Weld Overlay, Revision 2
GEH-VT-204, Procedure for In-Vessel Visual Inspection (IVVI) of BWR 4 RPV Internals, Version 12
GE-PDI-UT-2, PDI Generic Procedure for Ultrasonic Examination of Austenitic Pipe Welds, Revision 4
GE-UT-247, Procedure for Phased Array Ultrasonic Examination of Dissimilar Metal Welds, Version 1
PDI-GL-002, Guideline for UT Examination of Corrosion Resistant Cladding, Revision B
QU-AA-335-002, Dye Penetrant Examination Procedure

Notifications

20411711	20428422	20482907	20481698	20483273	20481435
20482460	20482689	20483011	20482400	20482709	20482710

NDE Inspection Reports and Data Sheets for RF 16
VT-10-074 for IWE Surfaces, summary 822200
UT-10-007 for UT of 1-BB-12VCA-014A-5, pipe to safe end, summary 107165
UT-10-005 for UT of 1-AB-26DLA-030-3, pipe to elbow, main steam system
PT-10-002 for PT of 1-CP-206-CSP-W2, pump casing weld, summary 250130
PT-10-003 for PT of RCPA-1 (A, B, C, D), Integrally welded attachment, summary 101015

Drawings
HC-8003-10, Steam Dryer Isometric Drawings for 0-90 and 180-270 degrees

Other Documents
Design Change Number 80101462, Install Reactor Cavity Rupture Drain Test Line Connection
UT Thickness Calibration Record for Drywell Wall Thickness Measurements for WO 60088598

Containment IWE Visual Examination Scope Memo from WEB to WAS, dated 7/28/2010
Apparent Cause Evaluation GL 2008-01, CR 70113599 on RHR HX Inlet Void Vulnerability
BWRVIP-75-A, BWR Vessel and Internals Project, 1012621, dated 10/2005
BWRVIP-26-A, BWR Vessel and Internals Project, 1009946, dated 2004
NUREG 0313, BWR Coolant Pressure Boundary Piping, Revision 2
FP-08-046, Hope Creek Generating Station - Design Margin for Drywell Shell

Section 1R11: Licensed Operator Requalification Program

Procedures
HC.OP-AB.BOP-0006, Main Condenser Vacuum, Revision 12
HC.OP-AB.CONT-0002, Primary Containment, Revision 9
HC.OP-EO.ZZ-0101, ATWS RPV Control, Revision 3

Other Documents
Simulator Scenario Guide SG-644

Section 1R12: Maintenance Effectiveness

Procedures
ER-AA-310, Implementation of the Maintenance Rule, Revision 7
ER-AA-310-1001, Maintenance Rule - Scoping, Revision 4
HC.OP-SO.BH-0001, Standby Liquid Control System Operation, Revision 14

Notifications (*NRC identified)

20489720*	20482793	20486854	20488045	20483946	20488249
20478132	20490123	20488888*			

Drawings
M-51-1, Residual Heat Removal, Revision 15

Other Documents
RCIC system performance monitoring report
RCIC system open engineering design changes report
RCIC system emergent work orders report

Section 1R13: Maintenance Risk Assessments and Emergent Work Control

Procedures
OP-AA-101-112-1002, On-Line Risk Assessment, Revision 5
WC-AA-101, On-Line Work Management Process, Revision 18

Other Documents
HCGS PRA Risk Evaluation for Work Week 1041 (10/03/10 – 10/09/10), Revision 1
HCGS PRA Risk Evaluation for Work Week 1047 (11/14/10 – 11/20/10), Revision 0
HCGS PRA Risk Evaluation for Work Week 1048 (11/21/10 – 11/27/10), Revision 0
HCGS PRA Risk Evaluation for Work Week 1051 (12/12/10 – 12/18/10), Revision 0

Section 1R15: Operability Evaluations

Procedures

HC.OP-ST.KJ-0006, Integrated Emergency Diesel Generator 1BG400 Test – 18 Month, Revision 38
HC.OP-SO.SN-0001, Nuclear Pressure Relief and ADS Operation, Revision 8
ER-AA-3003, Cable Condition Monitoring and Aging Management Program, Revision 0
ER-HC-1051, Leakage Reduction Program, Revision 0
OP-AA-108-115, Operability Determinations, Revision 3
OP-HC-108-115, Operability Assessment and Equipment Control Program, Revision 8

Drawings
241152-A-1550, Hope Creek Switching Station, 500 KV Switchyard

Notifications (*NRC-identified)

20486526	20390163	20481268	20486356	20486763	20486762
20482823	20482824	20482825	20483353	20457840	20428422
20468321*	20443483	20447552	20451100		

Orders

80102783	70091363	80102561	80102605	70115795	60090119
70111130	80102932				

Calculations
E-9, Standby Class 1E Diesel Generator Sizing, Revision 8
H-1-ZZ-MDC-1880, Post-LOCA Exclusion Area Boundary, Low Population Zone, and Control Room Doses, Revision 3
11-92, Sheet 6, Reactor Building Flooding

Other Documents
Operability Evaluation 10-02
Operability Evaluation 10-04
Station Service Transformer cable testing data reports
EPRI Report 1020805, Plant Support Engineering: Aging Management Program Guidance for Medium-Voltage Cable Systems for Nuclear Power Plants
Tan Delta Cable Testing Information Document
Institute of Electrical and Electronic Engineer Society (IEEE) Standard 400, IEEE Guide for Field Testing and Evaluation of the Insulation of Shielded Power Cable Systems
Technical Evaluation 70109076-0080
Technical Evaluation 70109076-0010
Technical Evaluation 70109076-0100
B RHR HX Leakage Trend Data and Projections
Temporary Configuration Change 4HT-10-025, Welded Housekeeping Bands for B RHR HX
Adverse Condition Monitoring and Contingency Plan H10-01
Temporary Log 10-032
Temporary Log 10-059

Section 1R18: Plant Modifications

Design Change Packages
DCP 80097309, HPCI Valve HV-8278 Replacement, Revision 1
DCP 80096650, Revise Calculation H-1-ZZ-MDC-1880

Drawings
54724-A, 8" Class 900 Parallel Disc Gate Valve with Limitorque SMB-1, Revision 3

50.59 Reviews, Screenings and Evaluations
50.59 HPCI Valve HV-8278 Replacement DCP 80097309, Revision 1
50.59 Safety Evaluation 80096650, Leakage Reduction Program Calculation, Revision 0

Notifications

20485505	20484194	20486230	20470663	20474444	20480579
20492477	20491096				

Procedures
HC.OP-IS.BJ-0101, High Pressure Coolant Injection System Valves – IST, Revision 60
CC-AA-5003, Design Analysis Health Performance Indicators, Revision 0

Orders

60086062	80097309	30138731	70040442	70112211

Other Documents
1BJ-HV-8278 MOV Diagnostic Test Instructions/Criteria
MIDAS Calculation DC Motor Operated Gate Valve 1BJ-HV-8278, Revision 4
Technical Evaluation 80096650-0210
Apparent Cause Evaluation 70112211

Section 1R19: Post-Maintenance Testing

Completed Surveillances
HC.MD-ST.AB-0001, MSIV Closure Trip Channel 18 Month Calibration, Revision 25
HC.IC-GP.ZZ-074, General Work Procedure MSIV Operator Maintenance, Revision 2
HC.IC-FT.SN-0009, ADS and Safety Relief Valve Operability Test, Revision 4
HC.OP-IS.BJ-0101, High Pressure Coolant Injection System Valves – IST, Revision 60
HC.OP-IS.BD-0101, Reactor Core Isolation Cooling System Valves – IST, Revision 55

Notifications (*NRC identified)

20491028*	20482851	20483383	20485505	20486106	20488005
20449844	20486253	20487713*	20485955		

Orders

30179396	60062301	30150942	60088072	60086062	50110085
60071812	50122924	80102654	60093426		

Section 1R20: Refueling and Outage Activities

Drawings
M-51-1, HCGS Residual Heat Removal, Revision 37

Procedures
HC.OP-IO.ZZ-0001, Refueling to Cold Shutdown, Revision 25
HC.OP-IO.ZZ-0004, Shutdown from Rated Power to Cold Shutdown, Revision 84
HC.OP-IO.ZZ-0005, Cold Shutdown to Refueling, Revision 31
OU-HC-105, Shutdown Safety Management Program – Hope Creek Annex, Revision 1

HC.OP-SO.BC-0002, Decay Heat Removal Operation, Revision 25
HC.OP-IS.ZZ-0001, Inservice System Leakage Test of the Reactor Coolant Pressure Boundary, Revision 39
OP-AA-108-108, Unit Restart Review, Revision 10
HC.OP-GP.ZZ-0002, Primary Containment Closeout, Revision 13

Notifications (*NRC-identified)

20485955	20482600	20482674	20481071	20485336	20485541
20485495*	20484271*	20484578	20481273	20483988	20483461
20485874*	20480720*	20479302*	20482344*	20483593	20482424
20482780	20482793	20482536*	20481390	20481261*	20481720*
20481117					

Orders

80102607	80102563	70099153	70115478	70115264	30179234

Other Documents
R16 Shutdown Risk Assessment, dated 10/1/2010
OP-AA-108-108 Startup Checklists
Plant Operations Review Committee – Startup Review Meeting Documentation
Design Analysis HCP.6-0244, Hope Creek Cycle 17 Rod Pattern Design Analysis, Attachment 2, Confirmation of GE14i Isotope Test Assemblies Non-Limiting Thermal Limits
GE14i Isotope Test Assembly Core Location Information
HC.RE-FR.ZZ-0008, Form 2, Core Fuel Assembly Serial Number Check Sheets
Hope Creek R16 Outage Update Reports

Section 1R22: Surveillance Testing

Procedures
HC.OP-IS.BD-0001, RCIC, Revision 49
HC.OP-ST.BH-0002, SLC Flow Test, Revision 28
HC.OP-ST.KJ-0006, Integrated EDG 1BG400 Test – 18 Months, Revision 39
HC.OP-ST.BC-0009, RHR Heat Exchanger Flow Measurement - 18 month, Revisions 13, 14

Notifications (*NRC identified)

20490150*	20490446*	20491354	20490203	20490123	20486591

Orders

50135109	50123140	50122117

Other Documents
2010-38, Shift Training Notebook – RCIC Oil Level, 12/27/2010

Section 1EP6: Drill Evaluation

Other Documents
Focused Area Drill Briefing Sheet for TSC (12/6/10)

Section 4OA2: Problem Identification and Resolution

Procedures
LS-AA-120, Issue Identification and Screening Process, Revision 10
LS-AA-125, Corrective Action Program Procedure, Revision 13

Notifications (*NRC identified)

20489855*	20398394	20410329	20412582	20412819	20418012
20423793	20447149	20448205	20465631	20475683	20479059
20489106	20489107				

Orders

80102951	70111248	70106683	70116946	701113898	70116932
70112292	70113583	70099564	70099566	701164946	70100323

Section 4OA5: Other Activities

Procedures
HC.MD-ST.PB-0014, Class 1E 4.16 kV Degraded Voltage 18 month Instrumentation Channel Calibration and Functional Test 10-A40101, Revision 5

Evaluations
70105083 OP 0020, Evaluate Hope Creek 4.16 kV 1E Undervoltage Relay Scheme, Revision 10

Drawings
E-0001-0, Single Line Diagram, Revision 24

Other Documents
Dry Cask Storage Building Surveys, dated 1/5/2010; 2/2/2010; and 3/1/2010
Independent Spent Fuel Storage Installation Surveys, dated 2/2/2010; 3/1/2010; 3/5/2010; 5/5/2010; and 6/28/2010

LIST OF ACRONYMS

ADAMS	Agency-wide Documents Access and Management System
ALARA	As Low As Reasonably Achievable
ASME	American Society of Mechanical Engineers
CAP	Corrective Action Program
CFR	Code of Federal Regulations
CR	Control Room
DM	Dissimilar Metal
EDG	Emergency Diesel Generator
EPRI	Electric Power Research Institute
ESF	Engineered Safety Feature
FAC	Flow Accelerated Corrosion
GL	Generic Letter
HPCI	High Pressure Coolant Injection
HRA	High Radiation Area
HX	Heat Exchanger
IMC	Inspection Manual Chapter
IR	Inspection Report
ISFSI	Independent Spent Fuel Storage Installation
ISI	Inservice Inspection
IVVI	In-Vessel Visual Inspection
LER	Licensee Event Report
LOCA	Loss of Coolant Accident
LOOP	Loss of Offsite Power
MSPI	Mitigating Systems Performance Index
NCV	Non-cited Violation
NDE	Nondestructive Examination
NEI	Nuclear Energy Institute
NRC	Nuclear Regulatory Commission
PCIV	Primary Containment Isolation Valve
PI	Performance Indicator
PSEG	Public Service Enterprise Group Nuclear LLC
RAI	Request for Additional Information
RCIC	Reactor Core Isolation Cooling
RCS	Reactor Coolant System
RHR	Residual Heat Removal
RPM	Radiation Protection Manager
RWP	Radiation Work Permit
SACS	Safety Auxiliary Cooling System
SDP	Significance Determination Process
SRV	Safety Relief Valve
SSC	Structures, Systems, and Components
ST	Surveillance Testing
SW	Service Water
TS	Technical Specification
UFSAR	Updated Final Safety Analysis Report
URI	Unresolved Item
UT	Ultrasonic Testing
VHRA	Very High Radiation Area